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CBM Injection/Falling Off Well-Test Parameters' Optimization and Study in the Middle of Qinshui Basin, China

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Abstract

As one effective mean of obtaining CBM parameters, injection/falling off well-test also has abnormal results. This paper studies process parameters' optimization such as injecting pressure, injecting volume, shut-in time and reservoir closure pressure, which will insure test procedure and results' reliability. In order to avoid ambiguity of well-test results it studies fluid and reservoir parameters' impacts on well-test interpretation results, and determines the range of parameters' value such as compression co-efficient, fluid viscosity and so on. The results prove that injection parameters' design affects field test success, determines whether test data truly reflect reservoir information or not, and its values may affect the accuracy of well-test interpretation. This paper's study will play an important role on solving injection/falling off well-test abnormal problems.

Key words: CBM reservoir; Injection/falling off well-test; Process parameters; Reservoir closure pressure; Well-test interpretation

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INTRODUCTION

The exploitation of coal reservoir is inseparable from well testing, and well testing can obtain the effective parameters of reservoir. Compared with past methods such as permeameter test method, mercury intrusion method, low-temperature liquid nitrogen injection method, injection/falling off well-test method can more truly reflect the information of reservoir .CBM is an unconventional natural gas resource , and its storage, migration and output mechanism have great differences. Due to lower critical desorption pressure and less free gas, majority of CBM exists in the form of physisorption; if it uses pressure build-down or build-up test , well shut- in may lead to harder recovery of productivity .Then injection-falling off well-test is widely applied on CBM wells. In order to guarantee CBM well test process's success ,this paper designers and optimizes injection parameters.

1. WELL-TEST PARAMETERS DESIGN

CBM injection/falling off well-test is to inject water into the formation by a stable rate, and injecting pressure is lower than formation crack pressure. After injecting the specified volume of liquid, it utilizes the pressure gauge data to make well-test interpretation that is placed in the wellbore. CBM injection/falling off well-test method needs to determine the following parameters' values .

(a)Injection time

The time of injection test should be long enough to exceed the wellbore storage effect stage, and as far as possible to reflect the dynamic pressure characteristics of formation radial flow stage. The radial flow beginning time is 1.5 times later than wellbore storage effect ending through analyzing semi-logarithmic curves for well testing interpretation, so the field test is ordered to overpass three times more wellbore storage time.

$$t_{inj} = 3t_{wbs}$$
$$t_{wbs} = (2.22C_s \mu e^{0.14S}) / Kh \quad (1)$$

(b)Injection rate

Injection rate cannot be too low, otherwise pressure sweeping area is relatively narrow; but injection rate cannot be too high, otherwise injection pressure may lead to formation crack. Injection flow fluctuation ratio shall not exceed 10%.

$$q_{inj} = \frac{0.471Kh(P_{\max} - P_i)}{B\mu[\log(\frac{8.085Kt_{inj}}{\varphi\mu C_t r_w^2}) + 0.87S]} \quad (2)$$

(c)Maximum injection pressure

During the injection test injected fluid is not allowed to crush the formation, otherwise reservoir parameters' interpretation is inaccurate. So the maximum injection pressure can be obtained as follows:

$$p_{\max} = \sigma_{\min} - 0.0098\rho_w D \quad (3)$$

(d)Shut-in time

Normally 12 hours' injection time and 24 hours' shut-in time is long enough to get reliable data from injection test; but for coal reservoir with poor property and conductivity it requires us to prolong the shut-in time that may be 6-10 times more than injection time.

$$t_{wf} = (6:10)t_{inj} \quad (4)$$

(e)Closingstress

Time square root method is often used to analyze the closing stress through micro-fracture experiment. According to the pressure characteristics of hydraulic fracturing there are two stages: the linear flow in the fracture firstly and then in the reservoir after crack closing. In addition, from the double logarithmic plot the value of fracture closure pressure can also be obtained at the end of reservoir-fracture linear flow line whose slop is 1/2.

2. CASE STUDY

2.1 Micro Fracture Test

The coal reservoir thickness is 7.1 meters, and chooses water as injection fluid. In a short time through water injection at a high rate it may produce pressure pulse, and then shut in for monitoring pressure changes. Field test parameters: 1 minute for injection, 0.05 cubic meters for water's volume, and 4 hours for shut-in. The gauge's pressure measuring data are shown in Figure.1.

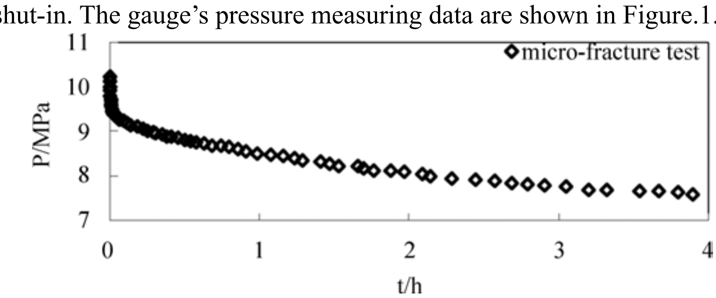

Figure 1
Micro Fracture-Test Diagram

By using pressure gauge's data the relationship curve between P and $t^{1/2}$ is drawn in Figure. 2.

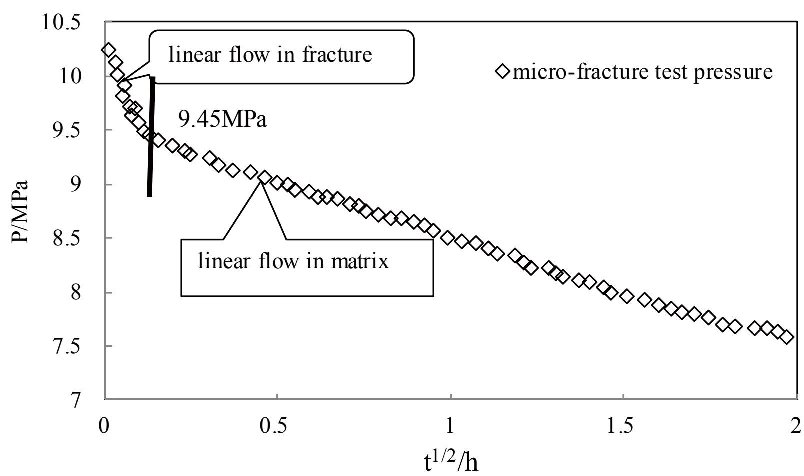

Figure 2
Closing Stress in the Micro Fracture Test

As can be seen from Figure. 2, there are two linear segments with different slopes, whose intersection point is at the value 9.45.During the field test the maximum injection pressure should be controlled below 9.45.

2.2 CBM Injection/Falling Off Welltest

CBM well property parameters in Qinshui Basin reservoir are set as follows: $\varphi=0.04$，$h=6m$，$r_w= 0.108m$，$B=1$，$\mu=0.98$ mPa • S，$C_t=0.0439MPa^{-1}$.

Using the Eq. (1) (2) (3) (4), well-test parameters can be obtained in Table 1.

Table 1
Injection/Falling Off Well-Test Parameters

Test parameters	Value
Injection rateq_{inj}	3.728 m^3/d
Injection timet_{inj}	12 h
maximum injection pressure	7.56 MPa
Shut-in pressure drop test time t_{wf}	24 h

Plot double logarithmic curve by the wellbore pressure gauge data, as shown in Figure. 3.

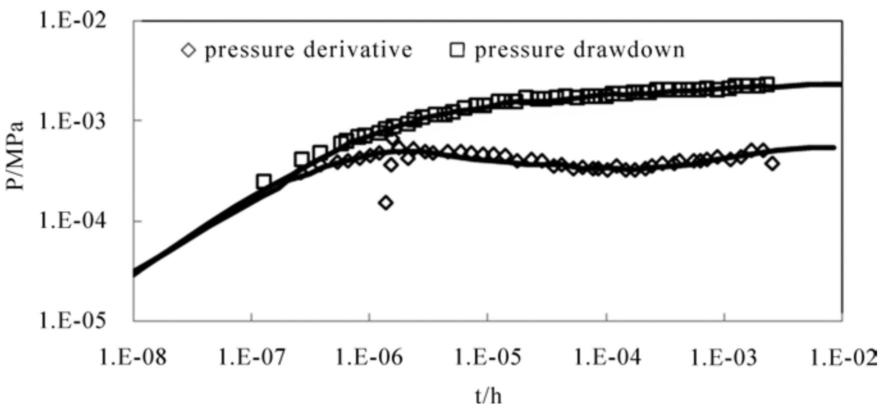

Figure 3
Log-Log Curve of Injection/Falling Off Well-test

The welltest interpretation analysis result is: reservoir pressure P_i=7.12MPa，effective permeability K=0.037mD.

2.3 Factors Sensitivity Analysis

(a)Viscosity of injection fluid

During the injection/falling off well test the injection fluid viscosity has great influences on well-test interpretation results as shown in Table 2.

Table 2
Water Viscosity Changes' Effects Chart

Fluid viscosity μ/mPa.s	Permeability k/mD	Skin factor S	Reservoir pressure Pi/ MPa	Investigation radiusRi/m	Boundary distance L/m
0.60	3.23	0.39	3.71	20.18	7.97
0.80	4.31	0.39	3.71	20.18	7.97
1.00	5.39	0.39	3.71	20.18	7.97

According to table 2 the water viscosity affects reservoir permeability greatly: the bigger the viscosity, the bigger the permeability.

(b)Reservoir porosity

Table 3
Porosity Changes' Effects Chart

Reservoir Porosity φ	Permeability k/mD	Skin Factor S	Reservoir Pressure Pi/MPa	Investigation RadiusRi/m	Boundary Distance L/m
0.01	2.18	3.89	4.55	165.14	76.17
0.03	2.18	4.46	4.55	95.34	43.95
0.05	2.18	4.73	4.55	73.85	34.02

According to table 3, porosity value has obvious impacts on skin factor, investigation radius and boundary distance, but fewer influences on permeability and reservoir pressure. From field practice and laboratory experiments it is found that porosity may be affected by depth, effective stress and coal rank, whose value range is between 0.008 and 0.016.

(c) Compressibility coefficient

Table 4
Compressibility Coefficient Changes' Effects

Compressibility coefficient Ct/MPa^{-1}	Permeabilityk/ mD	Skin FactorS	Reservoir Pressure Pi/ MPa	Investigation RadiusRi/m	Boundary Distance L/ m
7.25×10^{-2}	5.29	0.65	3.71	15.81	6.18
1.37×10^{-3}	5.29	-1.38	3.71	115.04	45.17
1.02×10^{-4}	5.29	-2.89	3.71	421.61	83.42

From the table 4 it can be seen that formation compressibility coefficient has no effects on permeability but great influences on skin factor, investigation radius and boundary distance. Even skin factor's value may change from positive to negative. According to the laboratory test statistics the compressibility coefficient range is from$1.0X10^{-4}$ to $9.9X10^{-2}$MPa^{-1}.

CONCLUSIONS

According to the work presented in this paper, the following conclusions are warranted:

(a) Injection/falling off well-test is an effective way to obtain CBM reservoirs information, and parameters' value can evaluate reservoir properties such as effective permeability, skin factor, etc;

(b)Based on injection fluid's choice and reservoir properties it can determine injection time, injection rate, injection pressure, shut-in time, closing stress and other parameters' values, which is of great significance to field test;

(c) The result of well testing interpretation is influenced by many factors. In order to ensure its accuracy this paper studies factors' effects and determines their values range such as porosity, viscosity, and compressibility coefficient, etc.

Nomenclature

t_{wbs}: the wellbore storage effect end time, h
t_{inj}: injection time, h
C_S: well-bore storage factor, m^3/MPa
μ: fluid viscosity, mPa·s
S: skin factor, dimensionless
K:permeability, mD
h: thickness , m
q_{inj} injection rate, m^3/d
p_{max}: maximum injection pressure，MPa
P_i:initial formation pressure，MPa
B:fluid volume factor, m^3/ m^3
φ:porosity， dimensionless
C_t:compressibility coefficient , MPa^{-1}
r_w:wellbore radius,m
$\sigma_{\min}$:minimum principal formation stress，MPa
ρ_w:fluid density, g/cm^3
D:coalbed middle depth , m
t_{wf}:shut-in time, h

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